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POLYMER TREATMENTS FOR D SAND WATER INJECTION WELLS

SOONER D SAND UNIT WELD COUNTY, COLORADO

Final Report
April 1997

By
Terry J. Cammon

October 1998

Performed Under Contract Subcontract G4S60323 and Prime Contract No. DE-AC22-94PC91008

Diversified Operating Corporation
Denver, Colorado

National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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Terry J. Cannon

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

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Abstract

Polymer-gel treatments in injection wells were evaluated for improving sweep efficiency in the D Sandstone reservoir at the Sooner Unit, Weld County, Colorado. Polymer treatments of injection wells at the Sooner Unit were expected to improve ultimate recovery by 1.0 percent of original-oil-in-place or 70,000 bbl of oil. The Sooner D Sand Unit was a demonstration project under the U.S. Department of Energy Class I Oil Program (DE-FC22-93BC14954) from which extensive reservoir data and characterization were obtained. Thus, successful application of polymer-gel treatments at the Sooner Unit would be a good case-history example for other operators of waterfloods in Cretaceous sandstone reservoirs in the Denver Basin.

Polymer Treatments for D Sand Water Injection Wells

Summary

The gel-polymer has remained stable and not degraded at the relatively high reservoir temperature of 220° F at the Sooner Unit; however, the polymer concentrations were probably too high. Three injection wells were treated with approximately 1200 lb of MARCIT™ Water-Cut 204® in 450 bbl of water at concentrations of 6000 to 10,000 ppm. The cross-linking agent was Water-Cut 684®. Polymer-gel treatments resulted in significantly reduced injectivity and kh calculations from pressure fall-off tests. Similar negative skins were computed before and after treatments and characteristic shapes of the pressure fall-off plots did not change. The polymer-gel has been stable at each injection well as indicated by continuation of elevated injection pressures and reduced injection rates. Before polymer-gel treatments, total water injection was about 2700 bbl water per day (bwpd), while the current injection rate is about 2300 bwpd. Injection at higher rates at treated wells is not possible because of pressure limitations of injection lines and reservoir-fracture pressure. No increase of oil production has been observed after 12 months from any producing well at the Sooner Unit following polymer-gel treatments. Total fluid production has decreased from wells which offset polymer treatments but the oil cut has remained the same. At the time of the first treatment in March 1996, the Sooner Unit was producing 391 bbl oil per day (bopd) and 1350 bwpd (78 percent water cut). By the end of February 1997, total production from the Unit was 174 bopd and 1109 bwpd (86 percent water cut). Cumulative oil from the Unit was 1,565,000 bbl or 22.7 percent of original-oil-in-place (6,900,000 stb). After one year, it cannot be said that the polymer treatments have resulted in a technical success by increasing oil cut.

Introduction

The Sooner Unit area encloses approximately 1440 acres (Figure 1) and produces 40° API oil from the lower-most Upper Cretaceous D Sandstone. The sandstone reservoir was deposited in a fluvial and estuarine setting with the majority of clastic sediments being deposited in an erosional valley as sea level rose. The D Sandstone has an average net thickness of 17 ft at a depth of 6200 ft. Reservoir rock has an average porosity of 11.5 percent with a geometric-mean absolute permeability of 20 md to air from core study. The reservoir consists of several stacked, sandstone packages as shown in figure 2. The depositional environment of the reservoir has resulted in strong north-south anisotropy. North-south well pairs often demonstrate fluid communication while east-west well pairs do not.

Production from the D Sandstone was established in 1969 in the Sooner Field one mile east from the Sooner "D" Sand Unit (Sooner Unit) in section 27, T. 8 N., R. 58 W. Methods used for exploration and development in the area were geology from well logs and wildcatting. The field consisted of a single well until 1980, when four additional wells were completed. The first productive D Sandstone oil well within the confines of the current Sooner Unit boundary (NWSE section 28, T. 8 N., R 58 W.) was completed in December 1985. By 1988, the productive surface area of the Sooner Unit reservoir was defined at about 720 acres with wells spaced on regular 40-acre production units. The 1440-acre Sooner Unit was created in September 1989. At that time, the unitized area had produced 772,000 stock-tank bbl (stb) of oil and 3,000,000 mcf of gas. The reservoir did not have a gas cap or free-water contact. Negligible formation water produced during primary depletion. Estimates of original-oil-in-place (OOIP) at the time the Sooner Unit was formed ranged from 5,300,000 to 5,900,000 stb. Estimates of ultimate primary recovery of oil by the unitization technical committee averaged 900,000 bbl and ranged from 850,000 to 1,100,000 bbl. Current estimate of OOIP is 6,900,000 stbafter information from additional drilling and seismic data.

Core and Electrical Log Descriptions of the D Sandstone

Basic to the characterizations of the D Sandstone reservoir at the Sooner Unit are data from conventional core analysis and electrical log calculation. The permeability-porosity cross-plot from D Sandstone cores is shown in figure 3. The plot suggests a porosity cut-off of between 6 and 8 percent for determination of net pay. The average net-pay porosity of the Sooner Unit reservoir is 11.5 percent. Statistics for permeability are summarized in table 1. The tabulation is intended to show that a permeability cut-off of 0.5 md is probably appropriate and a value of 0.74 for Dykstra-Parsons coefficient of permeability variation results when a log-normal frequency plot is made as shown in figure 4.

Calculations of net-pay properties from electrical logs are summarized in table 2. Net-pay thickness averages 17 ft (+/- 8 ft) with a maximum of 34 ft. At the Sooner Unit, criteria used to identify productive intervals include 1) resistivity of greater than 30 ohm-m, 2) gamma ray of less than 30 API units, micro-resistivity and caliper log readings indicating mud-cake buildup and 3) density-log porosities of greater than 8 percent. Calculations of water saturations are qualitative but are performed with reasonable success using a standard Archie equation for sandstones. The formation water is very fresh and a value of 0.06 ohm-m is used for water resistivity (R_w) at formation temperature of 220°F. Using the medium-induction curve value for formation resistivity (R_t) produces reasonable values for water saturation. A shale content of 35 percent from gamma-ray readings and water saturation of 60 percent are used to discriminate the net-pay from non-reservoir rock as summarized in table 2. The D Sandstone did not produce formation water during primary depletion and it is assumed that the reservoir water saturation was initially at irreducible conditions. Special core analysis indicates a value for irreducible water saturation of 19 percent.

Historical Background of Waterflooding the D Sandstone

Waterflooding of D Sandstone reservoirs began in the 1960's. Production by primary depletion from the D Sandstone has been good to excellent; however, secondary recovery by waterflooding has been disappointing. In 1974, there were 37 waterflood projects in the D Sandstone in Colorado according to a U.S. Bureau of Mines Report of Investigations (Biggs and Koch 1974). Data from the 37 D Sandstone waterfloods indicates incremental recovery of only 50 stb/ac-ft by waterflooding from 65 percent of the projects. Waterflood projects in the general vicinity of the Sooner Unit had marginal to negative incremental reserves compared to primary production extrapolations. Table 3 shows data from the waterflood projects in the area of the Sooner Unit.

Bureau of Mines Report of Investigations No. 7959, which tabulated statistics in 1974 on waterflooding oil fields in Colorado, is an excellent resource for production data from D

Sandstone reservoirs in the Denver Basin. However, the authors of the report did not attempt to qualify the statistics on recovery by giving reasons for good or poor recovery. Coincidentally after the report was published, interest waned for waterflooding the D Sandstone in the Colorado portion of the Denver Basin. These statistics were subsequently used by engineers on technical committees for proposed waterflood projects to demonstrate that the D Sandstone was a poor waterflood candidate. Between 1974 and 1992, only two waterflood projects were approved by the Colorado Oil and Gas Commission. Some of the popular reasons which were proposed by engineers for poor waterflooding recovery were 1) high Dykstra-Parsons coefficient of permeability variation and 2) high gas-saturation at the end of primary depletion.

The average primary recovery of D Sandstone waterflood projects in the area surrounding the Sooner Unit, shown in table 3, is 16.1 percent of OOIP. The total recovery after primary and waterflooding is 17.7 percent. An average incremental recovery of only 1.6 percent after waterflooding is demonstrated by these fields. All of these waterflood projects, except the Jackpot Field, are technical failures. The decision to risk waterflooding at the Sooner Unit was influenced to a large degree by the fact that the Sooner reservoir thickness is nearly double the average of the fields listed in table 3.

Production Response to Polymer Treatment

Three injection wells were treated with polymer-gel during 1996. The SU 10-28 was treated in March, the SU 3-21 was treated in June and the SU 15-21 was treated in August (see figure 1 for well locations). No increase of oil production has been observed after 12 months from any producing well at the Sooner Unit following polymer-gel treatments. Total fluid production has decreased from wells which offset polymer treatments but the oil cut has remained the same. The most notable change in waterflood operations is greater injection pressures at the treated wells. Wellhead pressures vary up to over 1200 psi when attempts are made to establish injection at pre-treatment rates which were at less than 100 psi wellhead pressure.

Production has been closely monitored at each well with frequent tank testing. The completion of the SU 21-16-9 well in September 1995, has had a dramatic impact on production from the Sooner Unit and it is necessary to compare production with and without the SU 21-16-9 to assess any impact on production resulting from the polymer-gel treatments. Figure 5 is a plot of total monthly production from the Sooner Unit since January 1995. Monthly oil, oil cut and water injection are shown. Two time lines are drawn to indicate the completion of the SU 21-16-9 and commencement of polymer-gel treatments. Completion of the SU 21-16-9 resulted in an increase in oil production from 8800 bbl per month to over 12,000 bbl per month. Production decline since April 1996, is mostly the result of water breakthrough at the SU 21-16-9 well. Figure 6 is a plot of total Unit production as a function of total cumulative oil produced. Figure 7 is a plot of total Unit production as a function of cumulative water injected. Figure 8 is a plot of Unit production with time, less allocated production from the SU 21-16-9 well. Trends are drawn through the monthly oil and oil cut prior to the commencement of polymer-gel treatments in March 1996. Figure 8 shows there has been no improvement in monthly oil production after polymer-gel treatments in the last 12 months. Figure 9 is a plot of Unit production less that allocated to the SU 21-16-9 well as a function of cumulative oil (minus that attributed to the SU 21-16-9). Trends are drawn for the monthly oil and oil cut. Figure 10 is a plot of Unit production less that allocated to the SU 21-16-9 well as a function of total water injection. Water production from the other wells is also shown. While there is no apparent change in the oil production trend, water production has decreased from about 1300 bwpd to 930 bwpd. Total water injection has been reduced from 2700 bwpd in March 1996, to 2300 bwpd in January 1997.

Summary of Polymer Treatments

The polymer treatments were designed to be relatively small volumes with high concentrations of polymer. The reservoir has a relatively high temperature of 220°F and it was thought that this might be a problem causing some degradation of gel strength. Therefore, treatments were designed to finish at concentrations of 10,000 ppm. Job logs for each of the three treatments are included in the appendix.

SU 10-28, NWSE Sec 28, T8N, R58E

On March 11, 1996, a MARCIT™ polymer-gel treatment was pumped in the SU 10-28 well. Perforation depth of the D Sand is at 6309 to 6334 ft. A total of 1150 lb Water-Cut 204® was injected with 418 bbl water in three stages with concentrations of 6000, 8000 and 10,000 ppm of polymer-gel. The average injection rate was 580 bpd with wellhead pressures from vacuum at the start to 1750 psi at the end. The well was shut-in for 6 days before injection was resumed at 204 bwpd with a wellhead tubing pressure of 575 psi. Post-treatment pressure fall-off test and temperature log were run on May 10. The fall-off test indicates a reduction of permeability-thickness (kh) from 43 to 24 md-ft (see table 4). A temperature log run after treatment indicates the injection water is confined to the D Sand perforations. A radioactive-tracer and temperature log was run in this well in 1993 and also showed all injection into the reservoir interval.

The only direct offset producer to the SU 10-28 well is the SU 7-28 well, located SWNW Sec 28. During the 3 months prior to the treatment the well averaged 29.1 bopd and 259.3 bwpd. An oil-cut of 9.4 percent is computed for this time period. During the last quarter, October through December, the well averaged 26.7 bopd and 260.6 bwpd. The current oil-cut is 9.3 percent.

Figure 11 and 12 are plots of allocated production for the SU 7-28 well. Figure 11 is production rate with time and figure 12 is producing rate with cumulative produced oil. Also shown on the graphs is the average daily injection at the SU 10-28 well. Trends of production history are computed through the recent data. The figures show that the is no change from the oil rate or oil-cut trends. The injection rate at the SU 10-28 well has been steady at about 300 to 350 bwpd. Injection wellhead pressures have increased from vacuum to about 1100 psi.

SU 3-21, NENW Sec 21, T8N, R58W

The Sooner Unit 3-21 well was treated June 6,1996, with 442 bbl of water with 1200 lb of WATER-CUT 204® MARCIT™ gel. Treatment consisted of three stages of 6000, 8000 and 10,000 ppm concentrations of polymer-gel. A pressure fall-off test performed after treatment indicates a reduction of permeability (kh) by 70 percent from 126 to 37 md-ft (see table 4). A temperature log run after treatment indicates the injection water is confined to the D Sand perforations at 6293 to 6322 ft. There has been no positive production response observed as of this time. Prior to treatment, the well was injecting an average of 568 bpd with no wellhead pressure. After treatment, the injection has averaged 291 bpd with wellhead pressure of about 1200 psi.

There are four wells which off-set the SU 3-21 injection well. These wells are the SU 13-16, SU 14-16, SU 4-21 and SU 6-21. During the 6 month period prior to the polymer-gel treatment, these wells averaged, in total, about 32 bopd and 735 bwpd. Average oil-cut is computed as 4.2 percent. During the six months following the treatment, these wells averaged 27 bopd and 573 bwpd. Average post-treatment oil-cut is computed as 4.5 percent. During December 1996, these wells averaged 23 bopd and 507 bwpd. The corresponding oil-cut is 4.3 percent. Figure 13 and 14 are plots of allocated production for the wells which off-set the SU 3-21 injection well. Figure 13 is producing rate with time and figure 14 is producing rate with cumulative produced oil. Also shown on the graphs is the average daily injection at the SU 3-21 well. Trends of production history are computed through the recent data. The figures show that there has been no positive change from the oil-rate or oil-cut trends. The injection rate at the SU 3-21 well has declined considerably from 600 to less than 300 bwpd. Injection wellhead pressures have increased from vacuum to about 1200 psi.

The treatment has resulted in reduction of water injection of 277 bpd or 49 percent. Both oil and total fluid production rates at offset wells are down by 25 percent. The pumping unit run-times at the SU 4-21 and SU 6-21 well are still decreasing. This indicates that steady-state injection-withdrawal has not yet been achieved (the reservoir-drainage volume is pressure depleting).

The total original-oil-in-place (OOIP) for this 200-acre portion of the Sooner Unit is calculated to be about 1,208,000 bbl. Cumulative secondary recovery to-date is 168,000 bbl or 13.9 percent of OOIP. The extrapolated secondary recovery for this injection cell at the SU 3-21 well is about 225,000 bbl to 2 percent oil-cut. The secondary recovery factor is computed to be 18.6 percent of OOIP.

SU 15-21, SWSE Sec 21, T8N, R58W

The SU 15-21 well was treated August 6, 1996, with 497 bbl of water with 1400 lb of WATER-CUT 204® MARCIT™ gel. The treatment was in three stages starting at 6000 ppm and ending with a maximum concentration of 10,000 ppm. The maximum wellhead-injection pressure was 810 psi. A fall-off test was performed pre-treatment and indicated a permeability (kh) of 453 md-ft for the 20 ft D Sand interval. Perforation depth is 6259 to 6288 ft (see table 4). A pressure fall-off test was not performed after treatment because treating rates and pressures indicated similar results with the treatments at the other two wells. Prior to treatment, the well was injecting about 650 bwpd with no pressure at the wellhead. After treatment, the well was injecting water at about 400 bwpd with a wellhead pressure of 250 psi.

Pressure Transient Tests

In addition to isolated tank testing of production wells, pressure transient tests were performed at injection wells to provide a quantitative measure of reservoir transmissibility and wellbore skin before and after polymer treatments. Pressure falloff tests were performed with pressure gauges at perforation depth and test durations from 72 to 148 hrs. Table 1 is provided as quantitative reference for how permeability or injectivity at the injection wells has been affected by the polymer-gel treatments. There were two post-treatment falloff tests. These tests indicate that the permeability-thickness (kh) was reduced from 126 md-ft to 37 md-ft at the SU 3-21 well. The SU 10-28 well indicates a reduction from 43 md-ft to 24 md-ft. Wellbore skin (S) did not change significantly before and after treatment. The SU 10-28 well had a skin of -4.3 before and -4.1 after while the SU 3-21 had a pre-treatment S of -4.7 and a post-treatment S of -3.7. Transmissibility and wellbore skin were computed using the Miller-Dyes-Hutchinson semi-log method. This is not the result which was anticipated as it was expected that kh would remain the same and skin would increase. No explanation can be offered for this result.

Conclusions

Gel-polymer treatments at three injection wells in the Sooner Unit have not resulted in oil production increases or water-cut decreases after one year of monitoring. Total fluid production has decreased at wells which offset the treated injection wells because of lower injection rates. Treatment size averaged about 1200 lb MARCIT™ Water-Cut 204® in 450 bbl of water at concentrations of 6000 to 10,000 ppm into reservoir intervals which average 17 ft of net thickness. The gel-polymer has remained stable and not degraded at the relatively high reservoir temperature of 220° F. Pre and post-treatment pressure falloff tests and temperature surveys were run in two of the treated wells. Temperature logs indicate no fluid movement outside of the reservoir intervals. Analysis of the falloff test data indicate significant reduction in kh without changes in wellbore skin. It is concluded that the treatment concentrations were probably too high and resulted in a negative impact on cashflow. Based on the experience from these treatments, a recommendation for future tests of the technology would be to use lower concentrations of less than 5000 ppm in a larger volume of 1000 bbl.

References

Biggs, Paul and Charles Koch. 1974. *Waterflooding of Oil Fields in Colorado*. U.S. Bureau of Mines Report of Investigations No. 7959.

SI Metric Conversion Factors

°API	141.5/(131.5+°API)		= gm/cm³
°F	(°F-32)/1.8		= °C
acre	x 4.046 856	E -01	= ha
ft	x 3.048*	E -01	= m
md	x 9.869 233	E -04	= μm^2
mile	x 1.609 344*	E+00	= km
psi	x 6.894 757	E+00	= kPa

* Conversion factor is exact

Table 1
Permeability Data from Four D Sandstone Cores in the Sooner Unit Area

	0.1 md cutoff	0.5 md cutoff	1.0 md cutoff
Geometric Mean k	8.8	21.3	23.6
Median Value k	20.8	28.0	28.2
Dykstra-Parsons Coef. of Variation	0.890	0.744	0.715
Cumulative Capacity	99.9%	99.8%	99.7%

Table 2
Summary of Log Calculations from 23 wells in the D Sandstone at the Sooner Unit

	Net Pay Thickness (feet)	Porosity Thickness (feet)	Hydro-carbon Thickness (feet)	Average Porosity	Oil Saturation
Maximum	34.0	2.887	3.725	11.0%	77.5%
Mean	16.6	1.408	1.899	11.5%	74.1%
Median	19.0	1.363	2.052	10.8%	66.4%
Standard Deviation	8.2	0.892	1.110	1.4%	5.5%

Table 3
Recovery by Waterflood from D Sandstone Fields Near the Sooner Unit

Field Name	Township - Range	Area - Acre	Acre-Feet	OOIP-Mbbl	Primary EUR-Mbbl	Waterflood EUR-Mbbl	Recovery Factor
Bijou	4-5N, 59-60W	1180	11800	7410	1400	1570	21.2%
Bijou-West	4N, 60W	1320	14520	7540	1198	1211	16.1%
Buckingham	8N, 58W	480	5760	2740	389	389	14.2%
Greasewood	6N, 61W	240	1920	1235	248	267	21.6%
Jackpot	6-7N, 59W	1440	11520	5515	1381	1762	31.9%
Orchard-East	4N, 60W	360	2160	1237	301	308	24.9%
Orchard-West	4N, 60W	200	1200	766	132	132	17.2%
Roggen-NW	2N, 63W	200	2000	1462	204	241	16.5%
Roggen-SE	2N, 63W	1050	10500	6267	496	552	8.8%
Masters	5N, 60W	360	2160	4070	335	354	8.7%
Total		6830	63540	38242	6084	6786	17.7%

Note: Waterflood EUR is total primary plus secondary recovery.

Table 4
Summary of Pressure Falloff Analysis from Water Injection Wells.

Test Well and Date	Injection Rate (bpd)	Injection BHP (psi)	Average Reservoir BHP (psi)	Test Duration (hrs)	kh (md-ft)	Skin (S)
SU 15-21 July 29, 1996	800	2446	2252	72	452	-4.2
SU 3-21* July 26, 1996	390	3786	2439	72	37	-3.7
SU 3-21 May 7, 1996	900	3514	2870	148	126	-4.7
SU 3-21 May 21, 1993	380	2259	1871	86	122	-3.8
SU 10-28* May 7, 1996	390	3989	2173	71	24	-4.1
SU 10-28 March 7, 1996	310	2109	1345	90	43	-4.3
SU 10-28 May 25, 1993	240	1604	1165	72	79	-3.6
SU 10-21A May 21, 1993	745	2502	2093	89	212	-4.4
SU 2-21 May 25, 1993	540	1271	1184	71	628	-4.8

* Indicates post-treatment test
Average reservoir pressure is based on an arbitrary 1000 ft radius

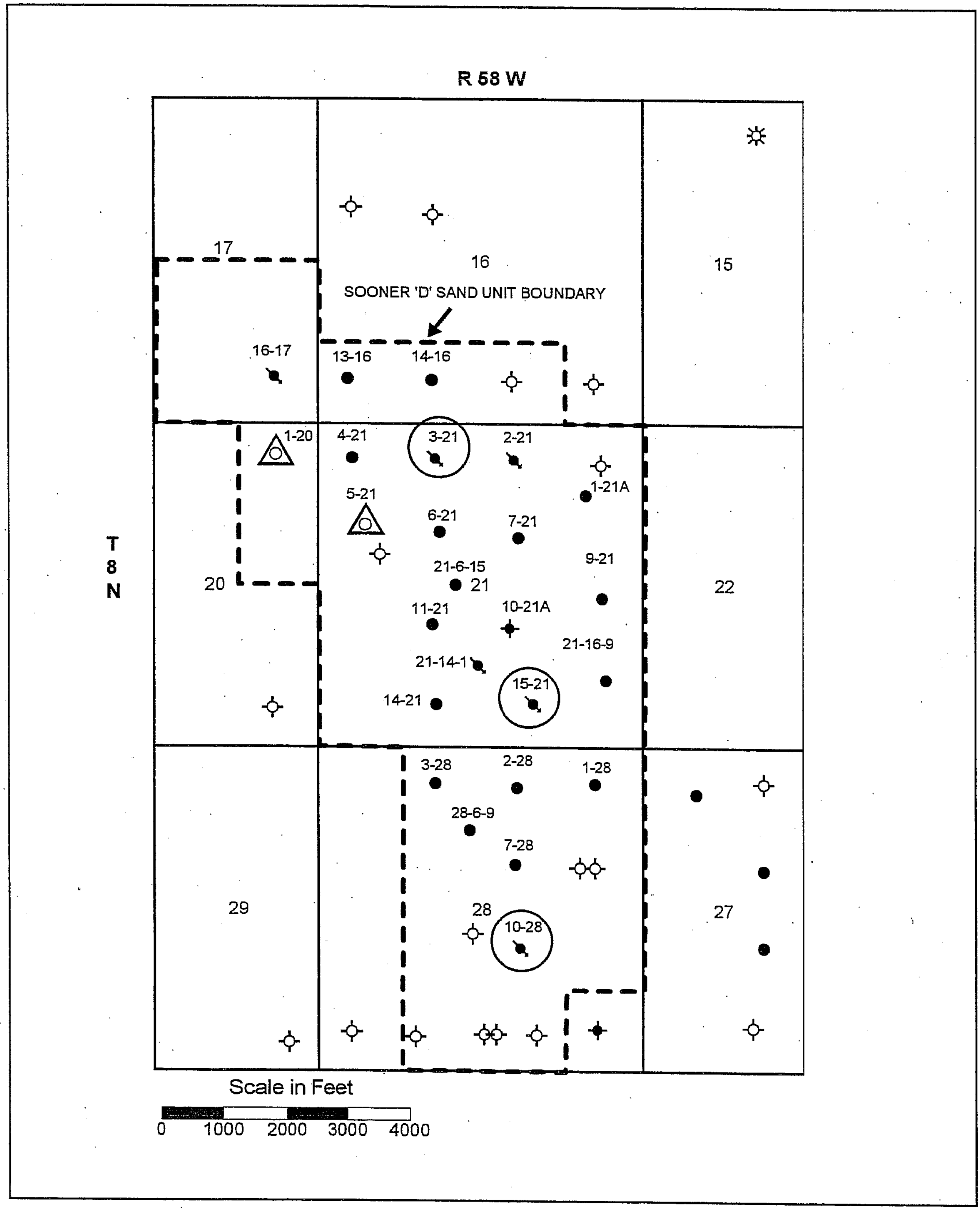

Figure 1: Map of Sooner "D" Sand Unit, Weld County, Colorado. Polymer treatments are shown in circles.

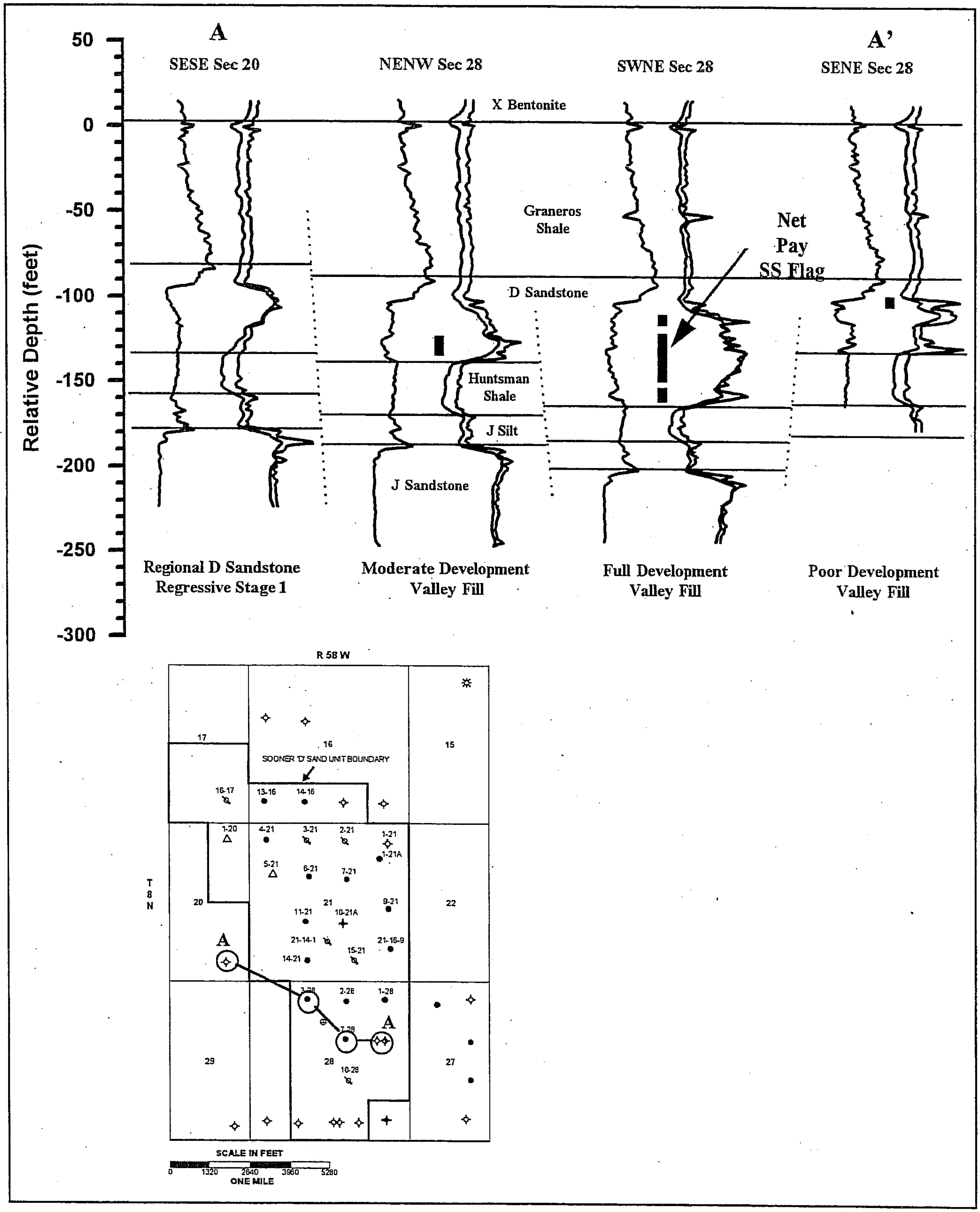

Figure 2: Cross-section showing D Sandstone reservoir at the Sooner Unit. The reservoir consists of several stacked packages deposited in valley-fill system. The erosional valley appears to have been influenced by paleo faulting.

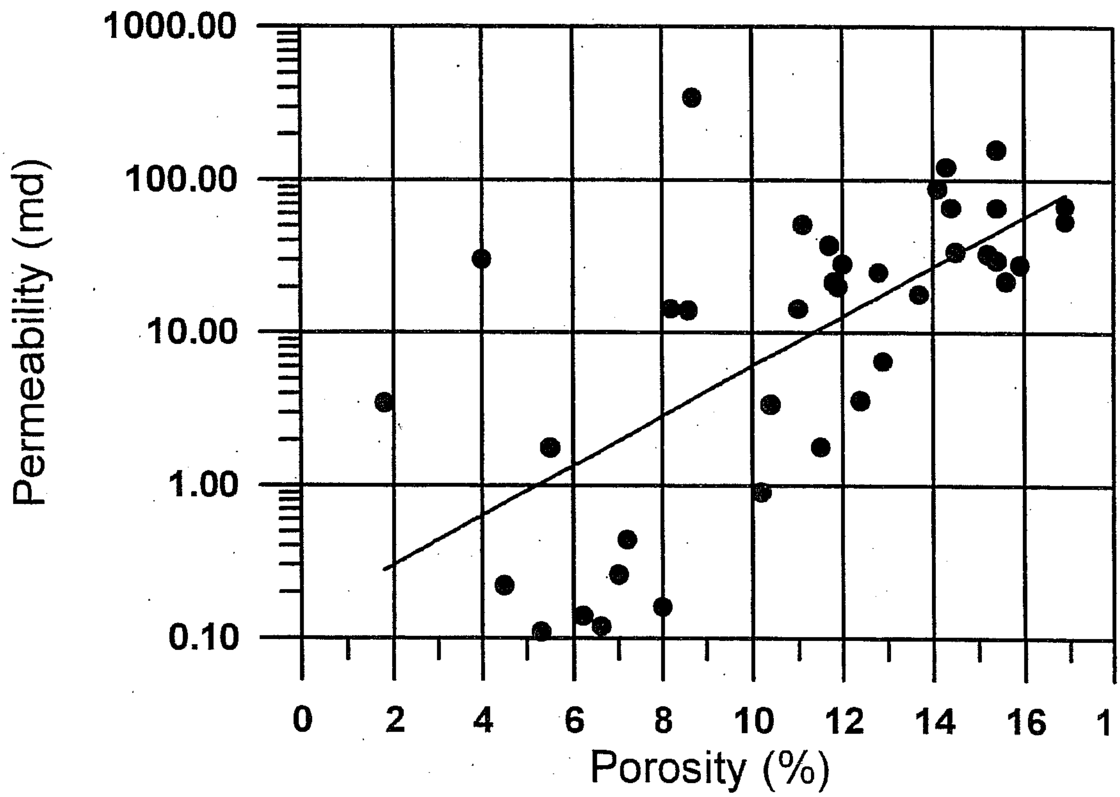

Figure 3: Permeability-porosity crossplot of D Sanstone. Average porosity at the Sooner Unit is 11.5 percent.

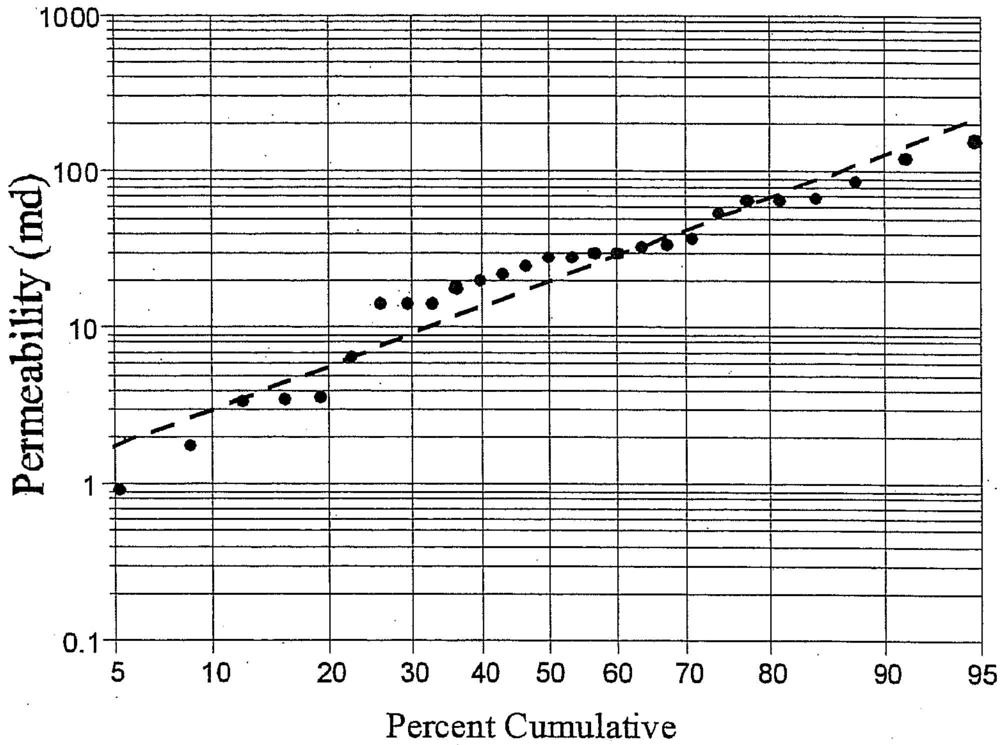

Figure 4: Plot of permeability variation using a cut-off of 0.5 md for the D Sandstone. A Dykstra-Parsons coefficient of 0.74 is calculated from this plot. The geometric-mean permeability is about 20 md.

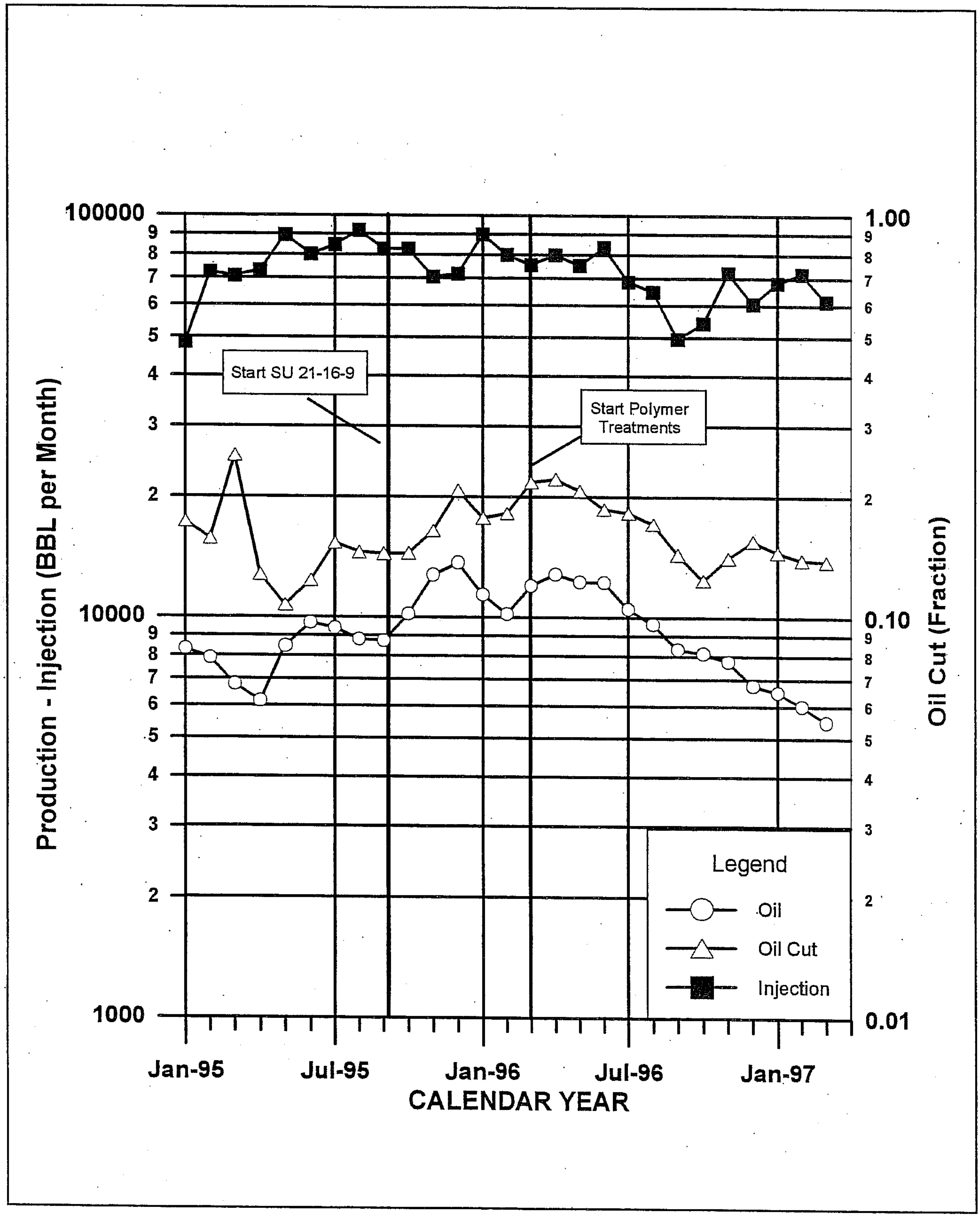

Figure 5: Production history with time for the Sooner D Sand Unit.

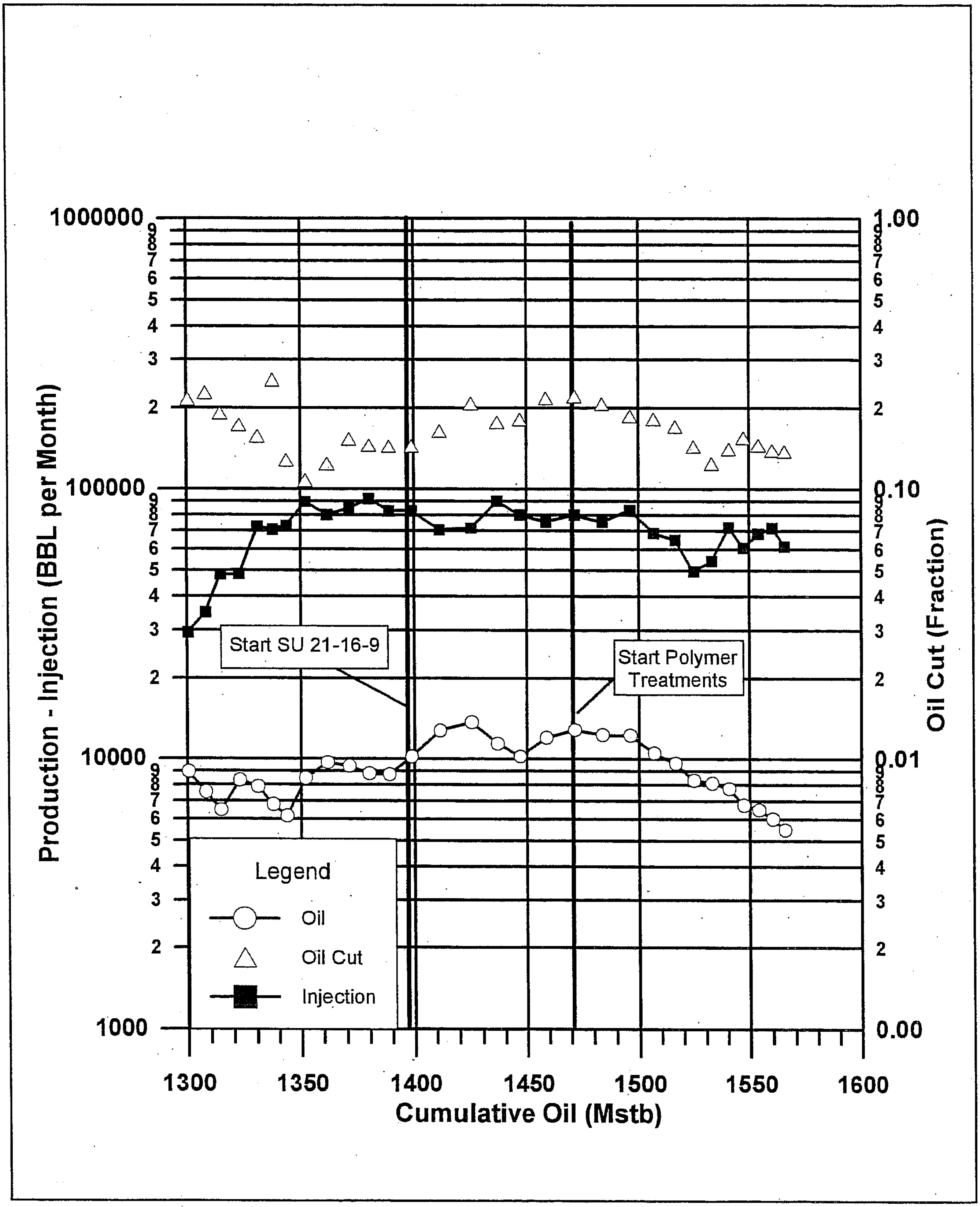

Figure 6: Production history with cumulative oil for the Sooner D Sand Unit.

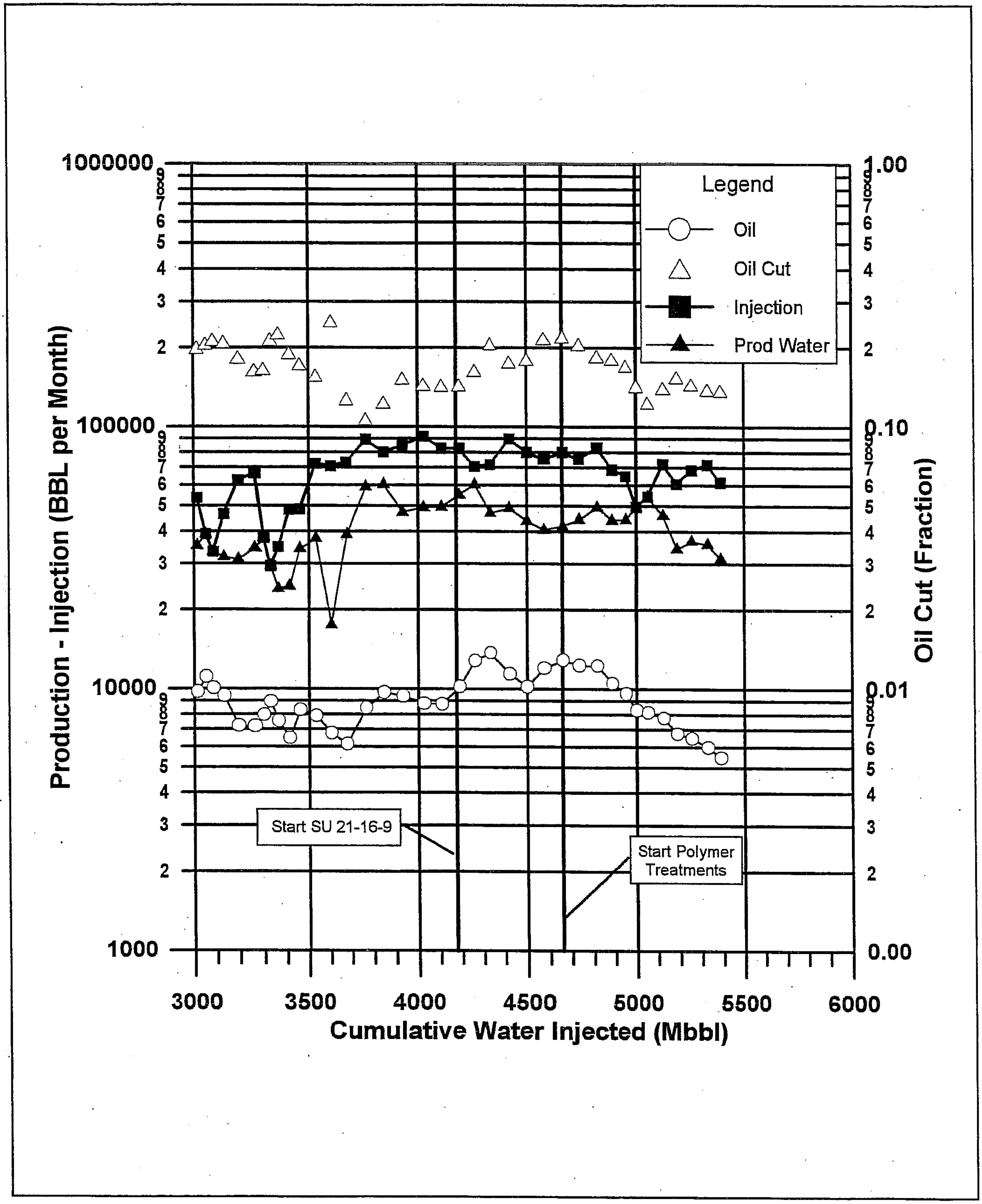

Figure 7: Production history with cumulative water injection for the Sooner D Sand Unit.

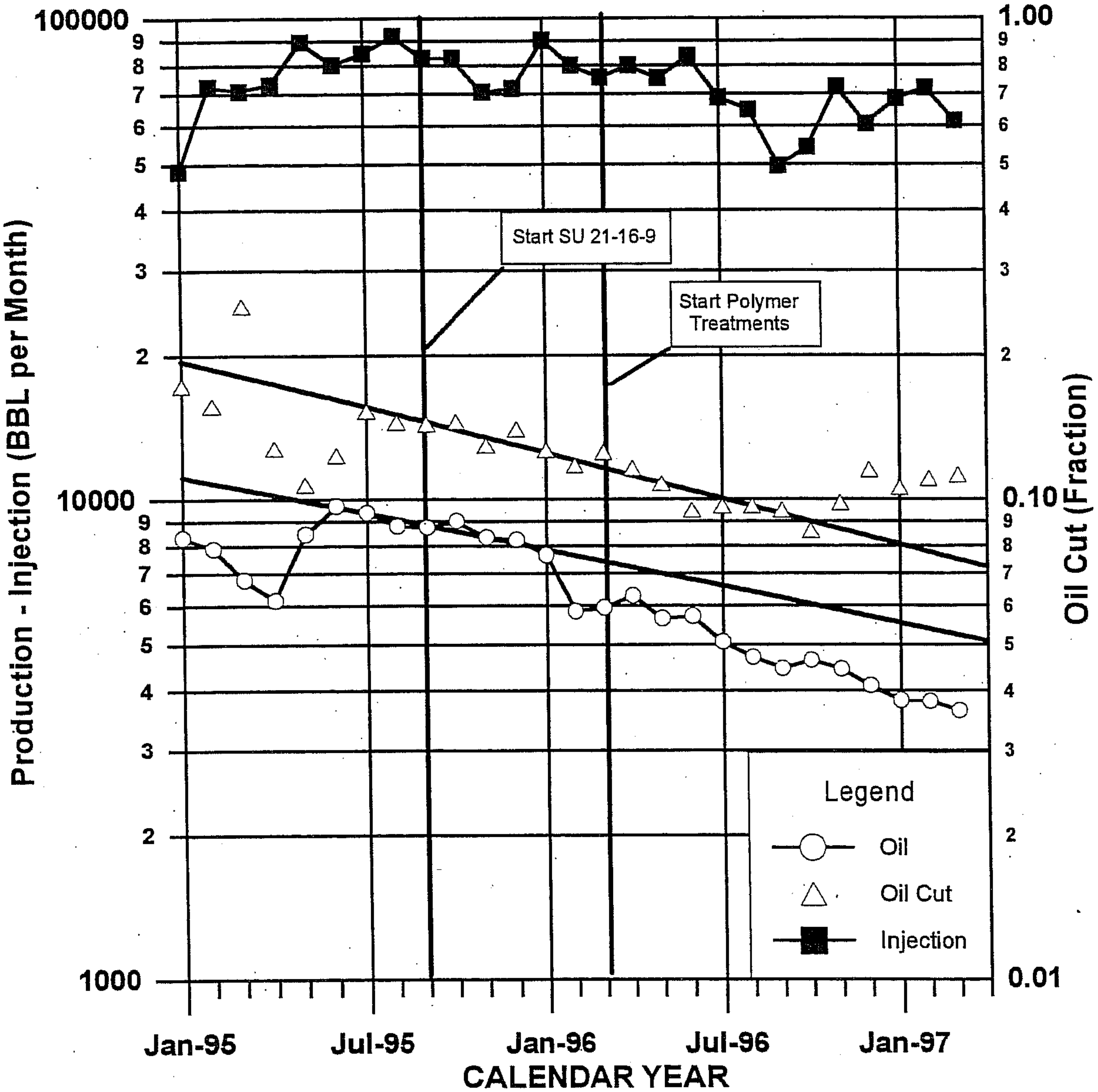

Figure 8: Production history with time excluding production from the SU 21-6-9 well. Base line production and oil-cut trends are shown.

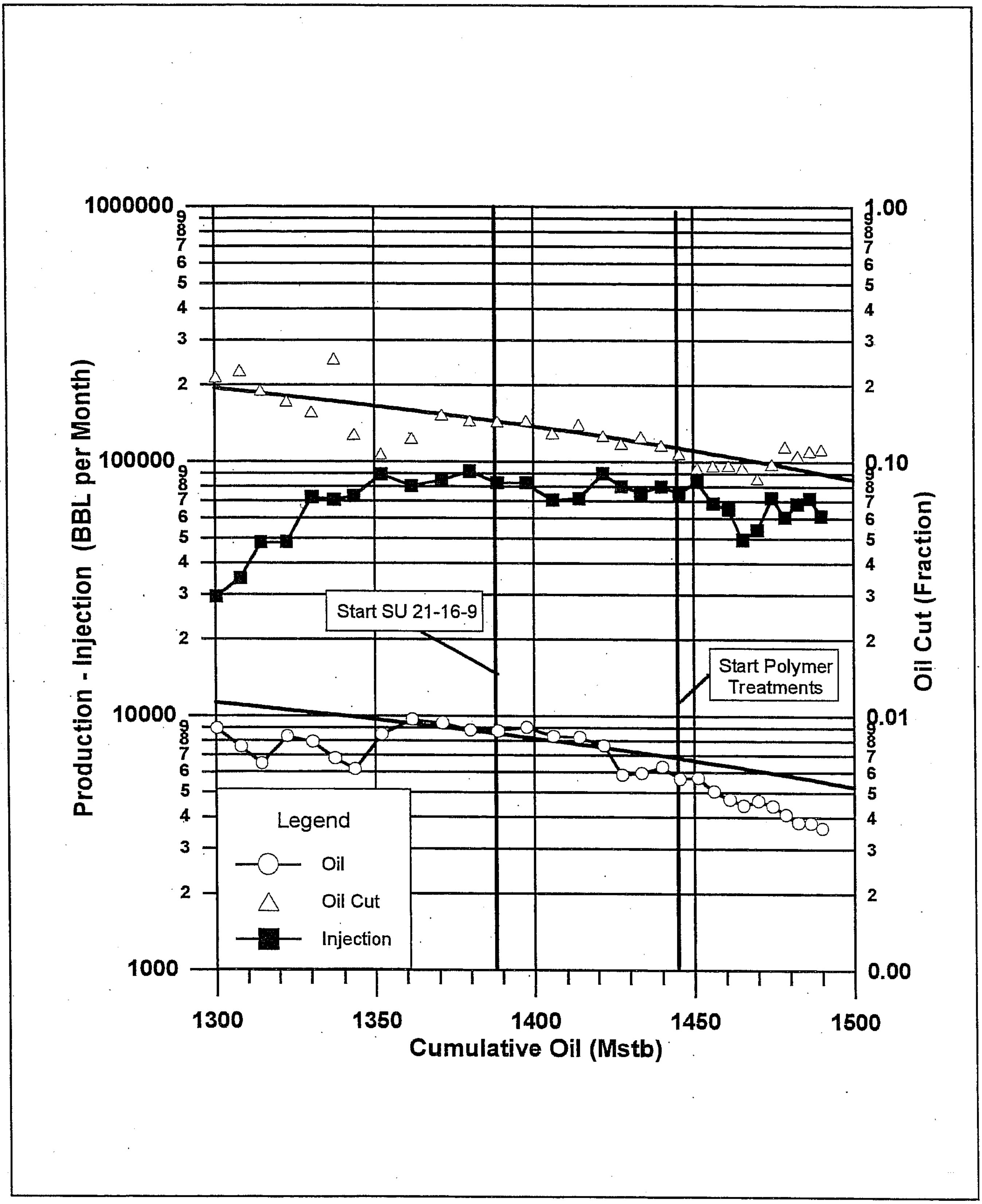

Figure 9: Production with cumulative oil excluding the SU 21-16-9 well.

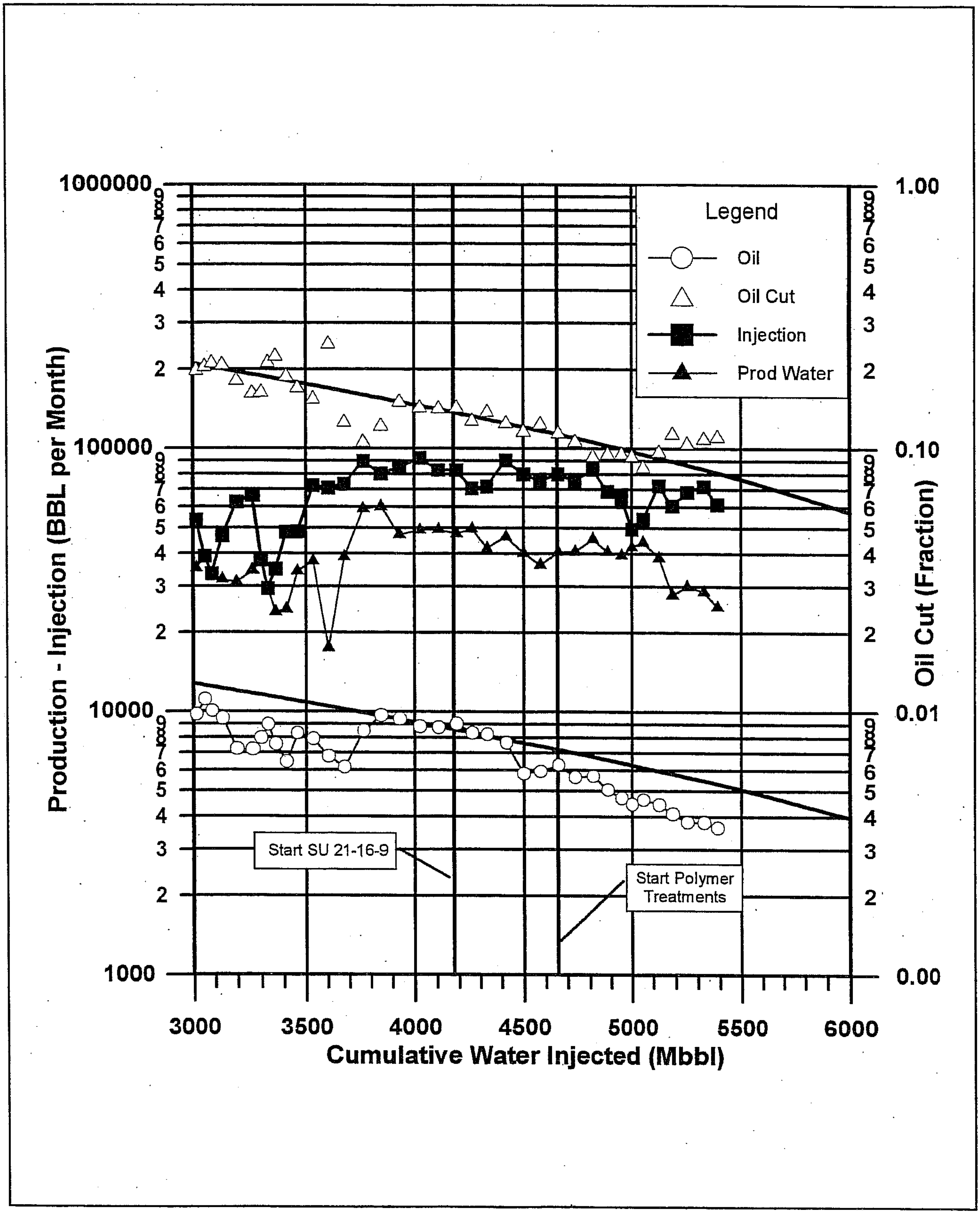

Figure 10: Production history with cumulative water injection without the SU 21-16-9 well. Base line trends of oil production and oil-cut are shown.

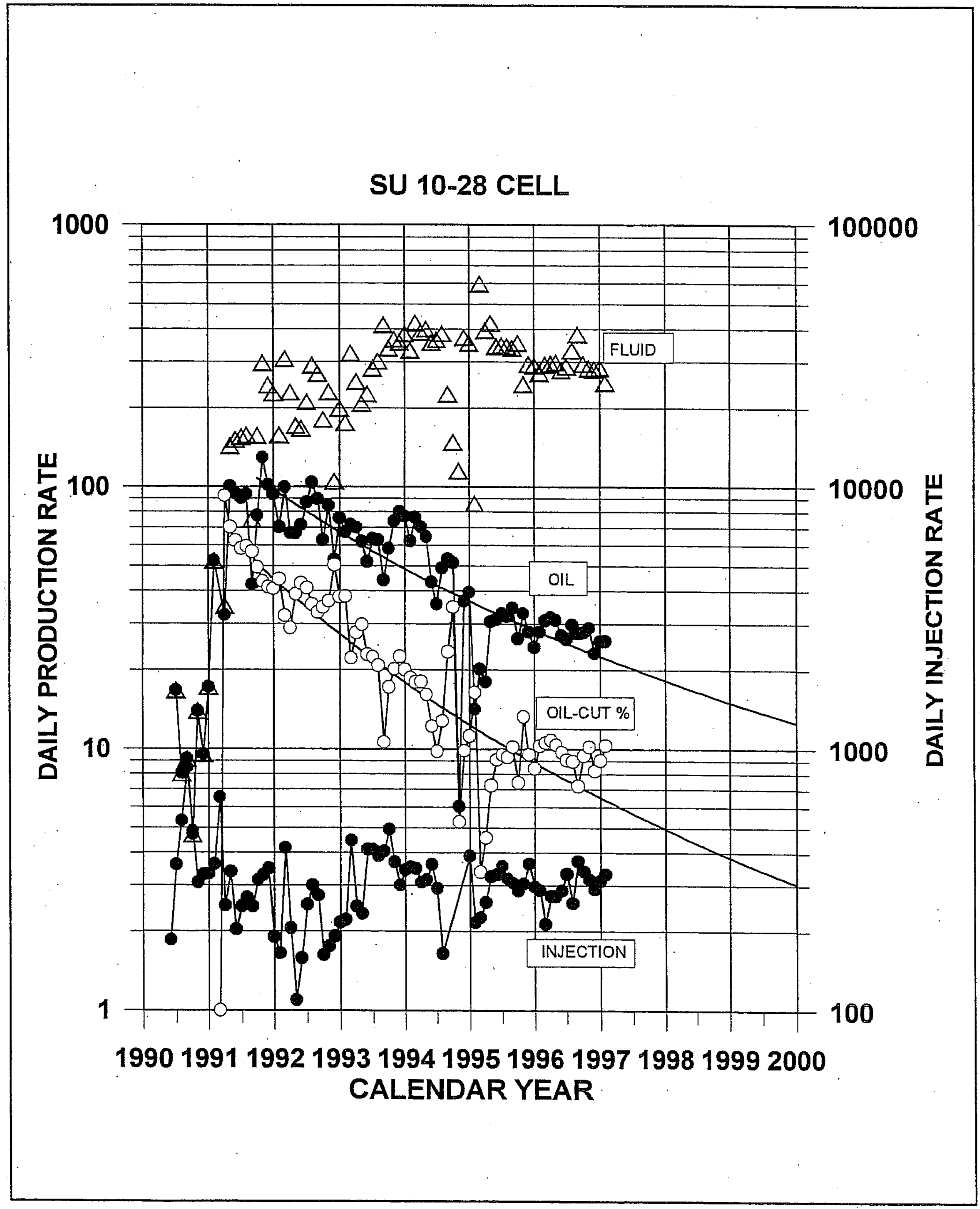

Figure 11: Production-injection history from SU 7-28 and 10-28

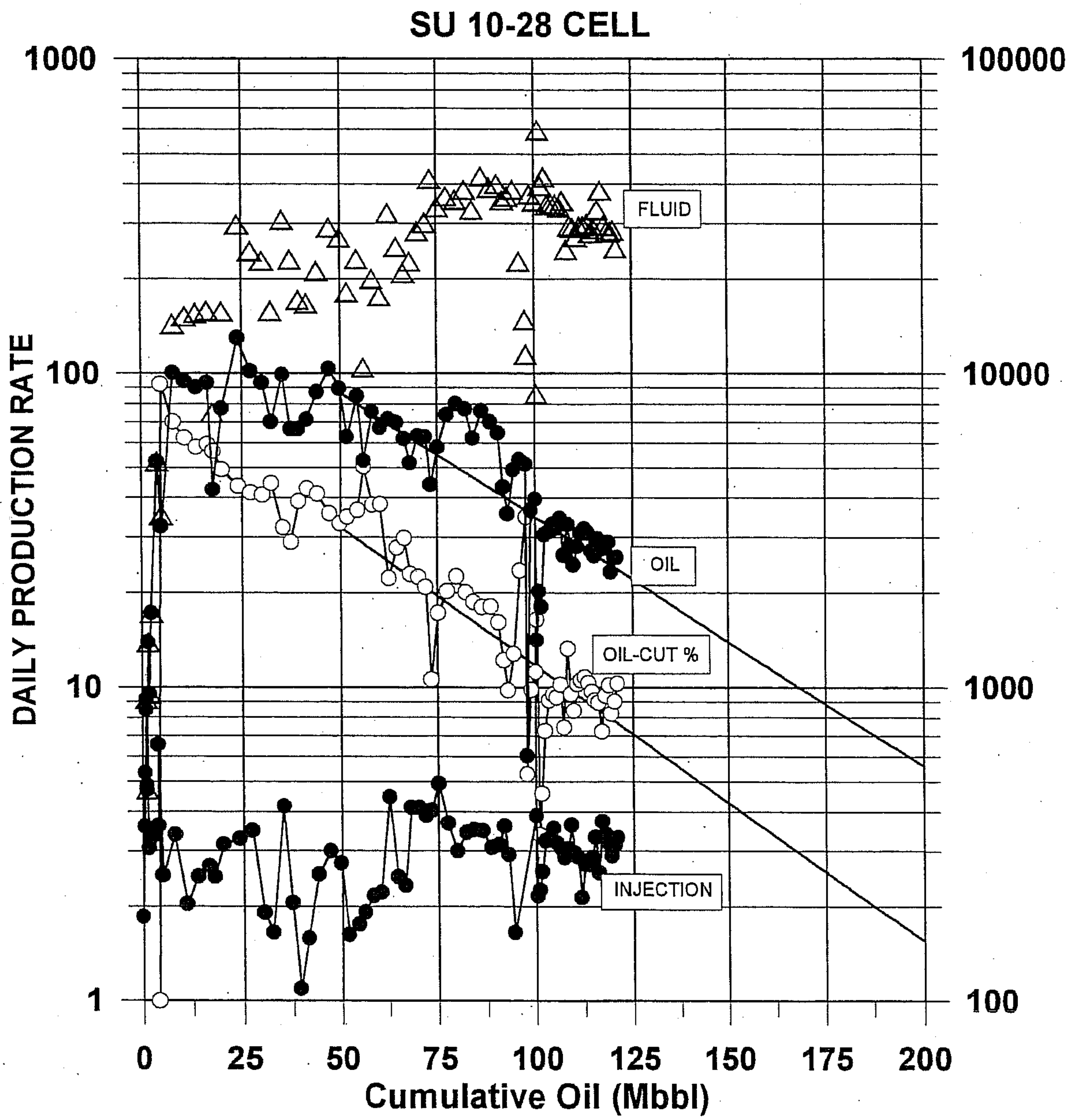

Figure 12: Production-injection history from SU 10-28 and 7-28 wells with cumulative oil from SU 7-28. Oil production has remained on trend after one year from polymer treatment at the SU 10-28 well. Injection pressure increased from vacuum to 1200 psi at the SU 10-28 well.

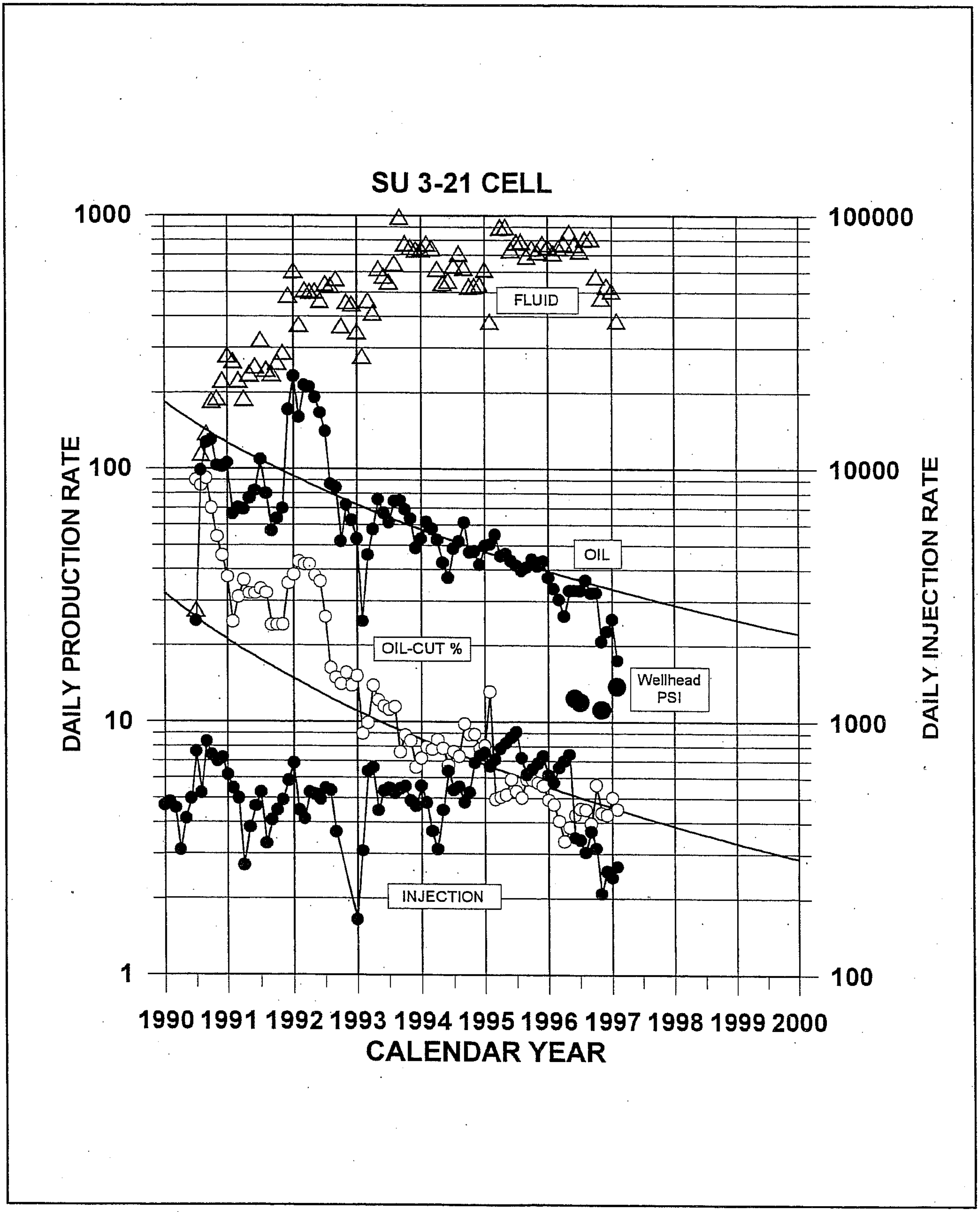

Figure 13: Production history from offset wells to the SU 3-21 injection well. Injection pressure increased from vacuum to over 1200 psi after polymer treatment.

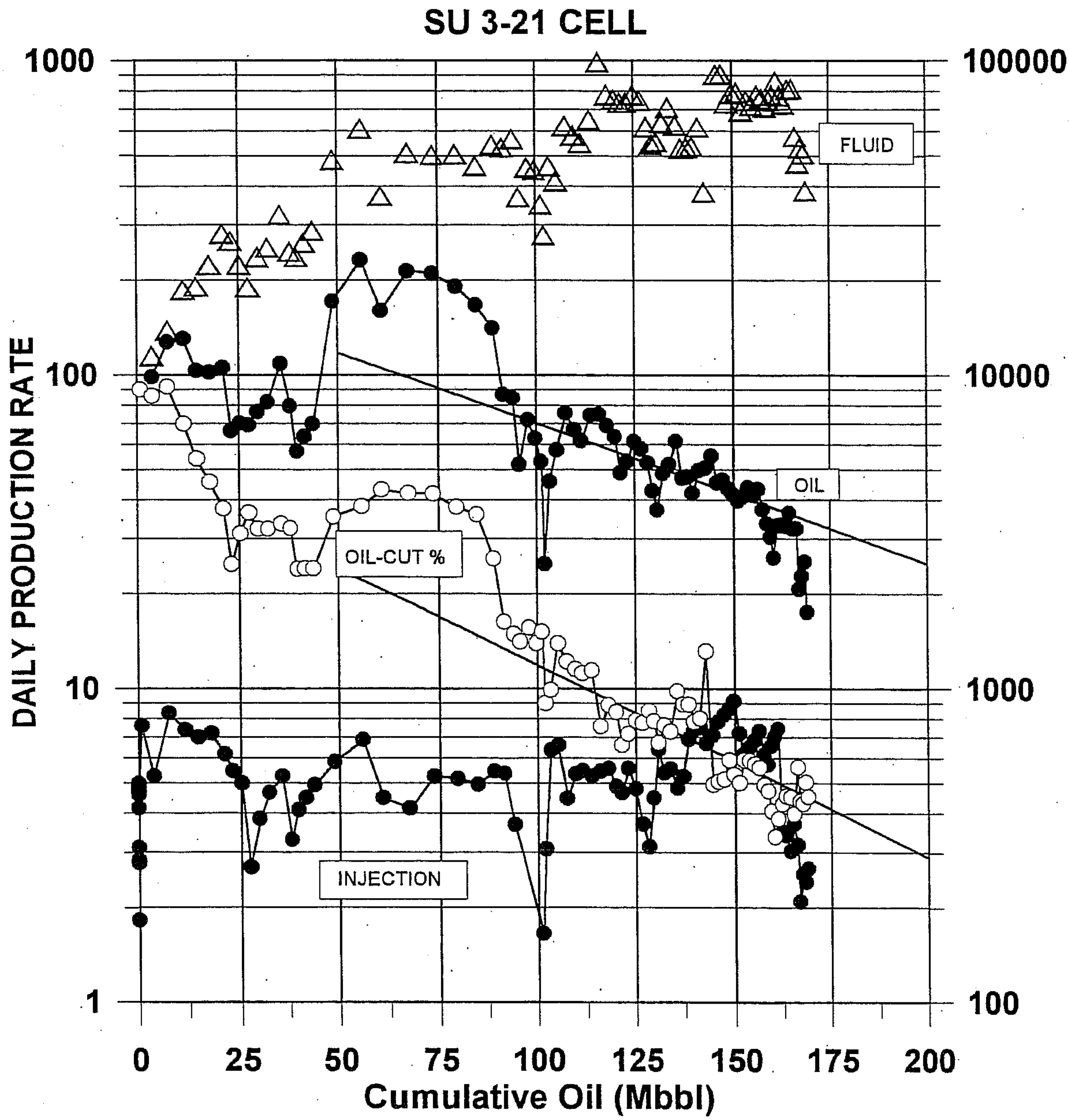

Figure 14: Production history from offset wells to the SU 3-21 injection well. Oil cut trend has remained steady but oil production has decreased with decreased injection.

MARCIT TREATMENT

COMPANY DIVERSIFIED OPERATING CORP.
FIELD Sooner Unit
WELL SU 10-28 P.W.

DATE	TIME	STAGE	RATE	CUMULATIVE LBS WATER-CUT® 204	CUMULATIVE GALLONS WC-684	INJ. PSI	BBLS PER STAGE	CUMULATIVE BWI	COMMENTS
3/11/96	7:45 p.m.	1	580			+20			Start Stage 1 - 6,000 ppm w/crosslinker
	9:15 p.m.	1	615	100	1.9	-21	47.0	47.0	
	10:58 p.m.	1	580	200	3.8	370	94.0	94.0	PSI at 60 BBLS - End Stage 1
	10:58 p.m.	2	580	200	3.8	370		94.0	Start Stage 2 - 8,000 ppm w/crosslinker
	11:36 p.m.	2	580	250	4.7	400	17.5	111.5	
3/12/96	12:12 a.m.	2	580	300	5.7	540	35.0	129.0	
	12:48 a.m.	2	580	350	6.7	660	52.5	146.5	
	1:26 a.m.	2	580	400	7.7	880	70.0	164.0	
	2:09 a.m.	2	580	450	8.7	1,040	87.5	181.5	
	2:38 a.m.	2	580	500	9.7	1,050	105.0	199.0	
	3:15 a.m.	2	580	550	10.7	1,050	122.5	216.5	
	3:54 a.m.	2	580	600	11.6	1,100	140.0	234.0	
	4:36 a.m.	2	580	650	12.6	1,000	157.5	251.5	
	5:26 a.m.	2	580	700	13.6	1,000	175.0	269.0	
	6:14 a.m.	2	580	750	14.6	850	192.5	286.5	
	6:58 a.m.	2	580	800	15.6	850	210.0	304.0	
	7:41 a.m.	2	580	850	16.6	1,400	227.5	321.5	Change bag filter air off triplex - get rate back
	8:13 a.m.	2	580	900	17.6	1,200	245.0	339.0	
	8:46 a.m.	2	580	950	18.6	1,320	262.5	356.5	
	9:26 a.m.	2	580	1,000	19.6	1,400	280.0	374.0	Air off triplex
	10:00 a.m.	2	580	1,050	20.6	1,650	298.0	392.0	End Stage 2
	10:00 a.m.	3	580	1,050	20.6	1,650		392.0	Start 10,000 ppm w/crosslinker
	10:30 a.m.	3	580	1,100	21.6	1,725	14.0	406.0	
	11:00 a.m.	3	580	1,150	22.4	1,750	26.0	418.0	End Stage 3
	11:00 a.m.	4	580	1,150	22.4	1,750		418.0	Water flush
	1:57 p.m.	4	580			875	50.0	468.0	

MARCIT TREATMENT

COMPANY DIVERSIFIED OPERATING CORP.
FIELD Sooner Unit
WELL #3-21

DATE	TIME	STAGE	RATE	CUMULATIVE LBS WATER-CUT® 204	CUMULATIVE GALLONS WC-684	INJ. PSI	BBLS PER STAGE	CUMULATIVE BWI	COMMENTS
6/6/96	10:35 a.m.	1	500			550			Start Stage 1 - 6,000 ppm w/crosslinker
	11:35 a.m.	1	500			650	21.0	21.0	
	11:47 a.m.	1	500	50	1.1	660	25.0	25.0	
	12:35 p.m.	1	500			800	41.0	41.0	
	1:00 p.m.	1	500	100	2.1	825	50.0	50.0	
	1:35 p.m.	1	500			850	62.0	62.0	
	2:12 p.m.	1	500	150	3.2	860	75.0	75.0	
	2:35 p.m.	1	500			875	83.0	83.0	
	3:25 p.m.	1	500	200	4.2	980	100.0	100.0	End Stage 1
	3:25 p.m.	2	500	200	4.2	980		100.0	Start Stage 2 - 8,000 ppm w/crosslinker
	3:35 p.m.	2	500			1,000	105.0	105.0	
	4:35 p.m.	2	500			1,050	26.0	126.0	
	5:07 p.m.	2	500	300	6.2	1,075	35.0	135.0	
	5:35 p.m.	2	500			1,125	47.0	147.0	
	6:35 p.m.	2	500			1,175	67.0	167.0	
	6:49 p.m.	2	500	400	8.2	1,175	70.0	170.0	
	7:35 p.m.	2	500			1,225	88.0	188.0	
	8:30 p.m.	2	500	500	10.1	1,275	104.0	204.0	
	8:35 p.m.	2	500			1,275	106.0	206.0	
	9:35 p.m.	2	500			1,300	127.0	227.0	
	10:11 p.m.	2	500	600	12.1	1,350	139.0	239.0	
	10:35 p.m.	2	500			1,375	148.0	248.0	
	11:35 p.m.	2	500			1,300	162.0	262.0	
6/7/96	12:10 a.m.	2	500	700	14.1	1,350	174.0	274.0	
	12:35 a.m.	2	500			1,375	183.0	283.0	
	1:35 a.m.	2	500			1,375	204.0	304.0	
	1:52 a.m.	2	500	800	16.1	1,400	211.0	311.0	
	2:35 a.m.	2	500			1,400	224.0	324.0	
	3:35 a.m.	2	500	900	18.1	1,400	247.0	347.0	
	4:35 a.m.	2	500			1,390	266.0	366.0	
	5:14 a.m.	2	500	1,000	20.2	1,390	282.0	382.0	
	5:35 a.m.	2	500			1,390	289.0	389.0	
	6:05 a.m.	2	500	1,050	21.3	1,390	300.0	400.0	End Stage 2
	6:05 a.m.	3	500	1,050	21.3	1,390		400.0	Start Stage 3 - 10,000 ppm w/crosslinker
	6:45 a.m.	3	500	1,100	22.2	1,400	14.0	414.0	
	7:25 a.m.	3	500	1,150	23.2	1,400	28.0	428.0	
	8:15 a.m.	3	500	1,200	24.2	1,850	42.0	442.0	
	8:15 a.m.	4	500			1,850		442.0	Start water flush
	10:40 a.m.	4	500			1,350	50.0	492.0	End job

MARCIT TREATMENT

COMPANY DIVERSIFIED OPERATING CORP.
FIELD Sooner Unit
WELL #15-21

DATE	TIME	STAGE	RATE	CUMULATIVE LBS WATER-CUT® 204	CUMULATIVE GALLONS WC-684	INJ. PSI	BBLS PER STAGE	CUMULATIVE BWI	COMMENTS
8/6/96	9:35 a.m.	1	500						Start Stage 1 - 6,000 ppm w/crosslinker
	10:50 a.m.	1	500	50	1.1	vacuum	25.0	25.0	
	12:02 p.m.	1	500	100	2.1	vacuum	50.0	50.0	
	1:12 p.m.	1	500	150	3.2	vacuum	75.0	75.0	
	2:24 p.m.	1	500	200	4.2	vacuum	100.0	100.0	End Stage 1
	2:24 p.m.	2	500	200	4.2	vacuum		100.0	Start Stage 2 - 8,000 ppm w/crosslinker
	4:02 p.m.	2	500	300	6.2	vacuum	35.0	135.0	
	5:40 p.m.	2	500	400	8.2	vacuum	70.0	170.0	
	7:19 p.m.	2	500	500	10.2	100	105.0	205.0	
	8:58 p.m.	2	500	600	12.2	150	140.0	240.0	
	10:37 p.m.	2	500	700	14.2	240	175.0	275.0	
8/7/96	12:17 a.m.	2	500	800	16.2	275	210.0	310.0	
	1:56 a.m.	2	500	900	18.1	310	245.0	345.0	
	3:35 a.m.	2	500	1,000	20.1	390	280.0	380.0	Change bag filter
	4:32 a.m.	2	500	1,050	21.1	410	298.0	398.0	End Stage 2
	4:32 a.m.	3	500	1,050	21.1	410		398.0	Start Stage 3 - 10,000 ppm w/crosslinker
	5:53 a.m.	3	500	1,150	23	450	28.0	426.0	
	7:13 a.m.	3	500	1,250	24.9	715	56.0	454.0	810 psi max. √
	8:33 a.m.	3	500	1,350	26.8	600	84.0	482.0	Bleed air off pump - down 10 min.
	9:25 a.m.	3	500	1,400	27.9	450	99.0	497.0	End Stage 3
	9:50 a.m.	4	500					497.0	Start Stage 4 - clean out valves, down 25 min.
		4	500				50.0	547.0	Vacuum in 4 min.